Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result of fast start pricing is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. Regulation revenues should be included as an offset to the daily uplift calculation for generators that receive regulation revenues, but are not currently included. The need for uplift should be calculated on a daily basis, as incorporated in the initial PJM market design, rather than on an hourly segment basis. The goal of uplift should be to ensure that units are not required to run at a loss on a daily basis. The goal should not be to lock in profits in some hourly segments and require uplift in other hourly segments. In the case where PJM makes multiday commitments, the uplift calculation should cover the entire multiday period rather than allowing a generator to be paid uplift on day one and earn significant profits on day three. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by hourly segments. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments. The net revenues in those new segments are not counted as contributing to covering costs in the initial segment. The reverse is also true. Uplift is paid even when total net revenues cover or more than cover costs when the entire day is included.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the

1 Losses occur when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Polar Vortex 2025 resulted in a significant increase in uplift payments as a result of the fact that PJM chose to prepare for the weather related risks of Polar Vortex 2025 in very different ways than for Winter Storm Elliott. Rather than rely on PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The results of Polar Vortex 2025 vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. PJM took additional advance actions to ensure transmission reliability. These commitments were not made to meet reserve requirements. Higher reserve requirements would not have addressed the Polar Vortex 2025 issues or cold weather reliability issues more generally.

The uplift associated with Polar Vortex 2025 was an expected outcome of conservative operations. This uplift is part of the way that PJM markets work and was the result of PJM's successful conservative operations approach to dealing with the cold weather risks of Polar Vortex 2025. PJM's commitment approach during Polar Vortex 2025 was significantly different than in 2024, for example. PJM committed only 1.4 percent of units on schedules less flexible than PLS during Polar Vortex 2025 compared to 17.2 percent during weather alert days in 2024. Nonetheless, improvements are needed to make the advance commitment process more predictable and transparent and to help ensure that these uplift charges are incurred only when needed for reliability.

4 Demand response payments are addressed in Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $442.1 million, or 202.3 percent, in the first nine months of 2025 compared to the first nine months of 2024, from $218.5 million to $660.6 million.
- **Types of energy uplift credits.** In the first nine months of 2025, total energy uplift credits included $181.5 million in day-ahead generator credits, $447.7 million in balancing generator credits, $28.9 million in lost opportunity cost credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $2.0 million in the first nine months of 2025.
- **Types of units.** In the first nine months of 2025, steam coal units received 9.1 percent of day-ahead generator credits, and combustion turbines received 53.5 percent of balancing generator credits and 64.8 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 36.3 percent of dispatch differential lost opportunity credits, and hydro units received 47.5 percent of dispatch differential lost opportunity credits
- **Concentration of energy uplift credits.** In the first nine months of 2025, the top 10 units receiving energy uplift credits received 37.5 percent of all credits and the top 10 organizations received 70.3 percent of all credits.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $3.2 million, or 12.3 percent, in the first nine months of 2025, compared to the first nine months of 2024, from $25.7 million to $28.9 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 65.2 percent of the $29.0 million of lost opportunity costs.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS

offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $17.9 million, of which PJM has resettled only $3.9 million, or 22.0 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** In the first nine months of 2025, total energy uplift charges increased by $443.1 million, or 203.8 percent, compared to the first nine months of 2024, from $217.4 million to $660.6 million.
- **Types of Energy Uplift Charges.** In the first nine months of 2025, total uplift charges included $181.4 million in day-ahead operating reserve charges, $478.1 million in balancing generator charges, $0.6 million in reactive charges, and $0.4 million in black start services.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM require wind units to request CIRs based on the maximum output used in the ELCC calculation for wind units. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[5]

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to

5 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. Such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of fast start pricing. The same is true of PJM's proposals to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs creates a tradeoff between minimizing production costs and reduction of uplift. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing approach.[6] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units routinely receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[7] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability by PJM in the day-ahead market.

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. That rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units

6 Fast start pricing was approved by FERC and implemented on September 1, 2021. See 173 FERC ¶ 61,244 (2020).

7 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

do not incur any costs to run and any revenue shortfalls are addressed by balancing generator credits.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch. PJM continues to pay uplift to units that do not follow dispatch. PJM and the MMU are actively working together to revise the definition of following dispatch to address these issues.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $17.9 million of incorrect uplift credits of which PJM has agreed and resettled only $3.9 million over the last two years, or 22.0 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases and generators offer to repay the credits.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Polar Vortex 2025 resulted in 51.3 percent of uplift credits in the first nine months of 2025. This level of uplift was consistent with the efficient operation of a reliable market. In anticipation of the cold weather and to avoid a repetition of the poor performance during Winter Storm Elliott, PJM made out of market commitments to mitigate generation performance risks associated with cold temperatures and natural gas commodity illiquidity over the weekend and intraday. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. As there is no multiday market, out of market actions taken before the market starts generally result in uplift. While the results of the Polar Vortex 2025 vindicated PJM’s strategy, the rules governing PJM’s actions should be more transparent and clearly documented. The results of Polar Vortex 2025 are preferred to Winter Storm Elliott and increased uplift is the expected result. Nonetheless, the uplift rules need significant improvement. In addition, the process of conservative operations and advanced commitments needs to be improved, formalized, and made as market based as possible in order to minimize uplift.

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift credits.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response.

The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraint control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing. Starting with this report, black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits, matching PJM's Market Settlements Reporting System.

Table 4-1 shows the uplift totals for each credit category during the first nine months of 2024 and 2025.[8] In the first nine months of 2025, energy uplift credits increased by $442.1 million or 202.3 percent compared to the first nine months of 2024. PJM commitment and dispatch decisions associated with the 2025 Polar Vortex caused significant increases in day-ahead generator credits, balancing generator credits, and lost opportunity cost credits.

The dispatch differential lost opportunity cost is a credit that exists only as a result of fast start pricing. This credit is paid to flexible resources that are artificially dispatched down, to an output level below the level that is economic at fast start prices, in order to accommodate inflexible fast start resources. Fast start pricing was introduced on September 1, 2021.

Table 4-1 Energy uplift credits by category: January through September, 2024 and 2025[9]

Category	Type	(Jan - Sep) 2024 Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Change	Percent Change	2024 Share	2025 Share
Day-Ahead	Generators	$93.8	$181.5	$87.7	93.5%	42.9%	27.5%
Balancing	Generators	$96.4	$447.7	$351.3	364.3%	44.1%	67.8%
	Canceled Resources	$0.1	$0.0	($0.1)	(74.8%)	0.0%	0.0%
	Lost Opportunity Cost	$25.7	$28.9	$3.2	12.3%	11.8%	4.4%
	Dispatch Differential Lost Opportunity Cost	$1.6	$2.0	$0.4	23.9%	0.7%	0.3%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Reactive Services	Generators	$0.9	$0.5	($0.4)	(41.2%)	0.4%	0.1%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(85.0%)	0.0%	0.0%
	Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Total		$218.5	$660.6	$442.1	202.3%	100.0%	100.0%

8 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 10, 2025.
9 Year to year change is rounded to $0.01 million.

Categories of Credits and Charges

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. For this reason, operating reserve charges do not always have the same value as operating reserve credits, since not all categories of uplift credits are paid for by the same PJM participants. For example, in the case of local constraint credits, credits are paid to generators in the form of balancing operating reserve credits but charges are allocated as local constraint charges. The same applies in the case of units scheduled day ahead for reactive support, for which the credits are paid in the form of day-ahead operating reserve credits but charges are allocated as reactive services charges. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by market participants in proportion to their day-ahead load, day-ahead exports, and virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

Starting with the *2024 Annual State of the Market Report for PJM*, black start credits and local constraint credits are not broken out individually and are included in the category of balancing generator credits. Similarly, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

	Credit Category	Charges Category	Charge Responsibility	Geographic Charge Aggregation
DAY-AHEAD	Day-Ahead Operating Reserve Transaction	Day-Ahead Operating Reserves for Transactions	Day-Ahead Load, Day-Ahead Exports, DECs & UTCs	RTO Region
	Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve for Generators		
	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response		
	Unallocated Negative Load Congestion Charges	Unallocated Congestion		
	Unallocated Positive Generation Congestion			
BALANCING	Balancing Generator Reserves	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	RTO, Eastern, and Western Region
		Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	RTO Region
	Canceled Resources	Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Lost Opportunity Cost (LOC)			
	Real-Time Import Transactions			
	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Local Constraints Control	NA	Transmission Owner	NA

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Generator Reactive Services		
	LOC Reactive Services		
	Condensing Reactive Services	Local Constraint Reactive Services	Transmission owner
	Synchronous Condensing LOC Reactive Services		
Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		
	Black Start LOC		

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type in the first nine months of 2025 and the first nine months of 2024. A combination of factors led to overall increased uplift payments, including unit specific issues and market issues of high fuel costs and PJM conservative operations during Polar Vortex 2025.

The longstanding rule which inexplicably exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits was terminated effective November 1, 2022. Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch and as a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines increased by $163.9 million or 168.7 percent during the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, CTs received 64.8 percent of lost opportunity cost credits. Lost opportunity cost credits increased by $28.9 million or 12.3 percent compared to the first nine months of 2024.

Uplift credits paid to steam coal units increased by $3.8 million or 8.6 percent in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, day-ahead uplift credits in the PEPCO Zone made up 82.3 percent of total day-ahead uplift credits, and accounted for 135.3 percent of the increase in day-ahead uplift during the first nine months of 2025, primarily as a result of unit specific issues for the Chalk Point 3 and 4 units. In the first nine months of 2025, steam coal units in the BGE Zone received 91.5 percent of day-ahead uplift credits paid to steam coal units, primarily as a result of unit specific issues for the Brandon Shores 1 and 2 units.

Uplift credits paid to non-coal (gas or oil fired) steam units increased by $121.0 million or 190.6 percent in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, gas or oil fired steam units received $184.6 million, 27.9 percent of total credits, compared to $63.5 million, 29.1 percent of total credits, during the first nine months of 2024. In the first nine months of 2025, the day-ahead uplift paid to gas or oil fired steam units was 201.1 percent higher than during the first nine months of 2024, and accounted for 122.1 percent of the total increase in day-ahead operating reserves. The increase in day-ahead generator credits paid to gas or oil fired steam units in the PEPCO Zone accounted for 122.1 percent of the overall increase in day-ahead generator credits in the first nine months of 2025. In the PEPCO Zone, gas fired steam units Chalk Point 3 and 4 received $152.2 million in uplift in the first nine months of 2025.[10] During the 2025 Polar Vortex, non-coal steam units received $132.4 million, or 71.8 percent of all credits received by non-coal steam units during the first nine months of 2025. Non-coal steam units received 39.0 percent of total uplift credits during the 2025 Polar Vortex.

Uplift credits paid to combined cycle units increased by $146.9 million or 1,471.2 percent in the first nine months of 2025 compared to the first nine months of 2024. This increase occurred primarily in January 2025 as a result of the commitments made in advance of the day-ahead energy market during the 2025 Polar Vortex. The 2025 Polar Vortex accounted for 89.3 percent of the uplift credits paid to combined cycle units, and accounted for 51.3 percent of total uplift credits during the first nine months of 2025.

In the first nine months of 2025, uplift credits to wind units were $6.0 million, up by 346.1 percent compared to the first nine months of 2024.

Table 4-4 Total energy uplift credits by unit type: January through September, 2024 and 2025[11] [12]

Unit Type	(Jan - Sep) 2024 Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2024 Share	(Jan - Sep) 2025 Share
Combined Cycle	$10.0	$156.9	$146.9	1,471.2%	4.6%	23.7%
Combustion Turbine	$97.2	$261.1	$163.9	168.7%	44.5%	39.5%
Diesel	$1.4	$2.7	$1.2	87.0%	0.7%	0.4%
Hydro	$0.9	$0.9	$0.0	1.2%	0.4%	0.1%
Nuclear	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Solar	$0.2	$0.8	$0.6	226.9%	0.1%	0.1%
Steam - Coal	$43.9	$47.6	$3.8	8.6%	20.1%	7.2%
Steam - Other	$63.5	$184.6	$121.0	190.6%	29.1%	27.9%
Wind	$1.4	$6.0	$4.7	346.1%	0.6%	0.9%
Total	$218.5	$660.6	$442.1	202.3%	100.0%	100.0%

10 See Table 4-14.

11 Table 4-4 does not include balancing imports credits and load response credits in the total amounts.

12 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2025. The largest share of day-ahead credits, 97.5 percent, went to steam units. Steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 53.5 percent of balancing credits and 64.8 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-5 Energy uplift credits by unit type: January through September, 2025

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Dispatch Differential Lost Opportunity Cost
Combined Cycle	1.3%	34.0%	0.0%	7.5%	1.0%	0.0%	18.2%
Combustion Turbine	1.2%	53.5%	0.0%	64.8%	22.9%	0.0%	18.1%
Diesel	0.0%	0.4%	0.0%	1.6%	74.3%	0.0%	0.3%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	47.5%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	2.8%	0.0%	0.0%	0.6%
Steam - Coal	9.1%	6.8%	0.0%	2.2%	1.9%	0.0%	9.8%
Steam - Other	88.4%	5.4%	100.0%	0.5%	0.0%	0.0%	1.8%
Wind	0.0%	0.0%	0.0%	20.6%	0.0%	0.0%	3.7%
Total (Millions)	$181.5	$447.7	$0.0	$28.9	$0.5	$0.0	$2.0

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[13] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[14]

Pool scheduled units are units that are committed in the day-ahead market based on economics. Units committed for reliability by PJM are units that are committed to satisfy reliability needs, regardless of whether the offers are economic. Self scheduled units are self committed by the generation owner and are not eligible for uplift. Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Balancing Uplift (Operating Reserve) Credits/ Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover all of their operating costs from market revenues. Balancing operating reserves include multiple credit types that are paid to units in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential lost opportunity cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. Balancing generator credits are the largest category of balancing operating reserves. Balancing generator credits are calculated by hourly segments as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time

13 See OA Schedule 1 § 3.2.3(b).

14 See OA Schedule 1 § 3.2.3(a).

offer (startup, no load, and incremental energy offer). Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Table 4-5 shows that combustion turbines (CTs) received 53.5 percent of balancing generator credits in the first nine months of 2025, or $239.7 million. Combined cycles (CCs) received 34.0 percent of balancing generator credits in the first nine months of 2025, or $152.0 million. During the 2025 Polar Vortex, the balancing generator credits to CCs exceeded CTs due to conservative operations commitments.

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal.[15] Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing generator credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Table 4-1 shows that balancing generator credits increased by 364.3 percent in the first nine months of 2025 compared to the first nine months of 2024.

CTs that operate on a day-ahead schedule tend to receive lower balancing generator credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. The day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, resulting in greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[16] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to

15 *See* "Operating Reserve Make Whole Credit Education," slide 13, PJM presentation to the Market Implementation Committee. (April 13, 2022) <https://pjm.com/-/media/committees-groups/committees/mic/2022/20220413/item-11a---operating-reserve-make-whole-credits-education.ashx>.

16 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-6 shows monthly day-ahead and real-time LOC credits in 2024 and the first nine months of 2025. In the first nine months of 2025, LOC credits increased by $3.2 million or 12.3 percent compared to the first nine months of 2024. The overall change was an increase, which included a $3.6 million decrease in day-ahead LOC which was offset by a $6.7 million increase in real-time LOC.

In the first nine months of 2025, wind units received $6.0 million of uplift, up by $4.7 million compared to the first nine months of 2024. Wind units that are capacity resources are now required to procure Capacity Interconnection Rights (CIRs) equal to the maximum facility output included in the calculation of their ELCC value. Wind units that are capacity resources are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should use the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs) as the definition of the foregone opportunity.

Table 4-6 Monthly lost opportunity cost credits (Millions): 2024 and January through September, 2025[17 18]

	2024			2025		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.8	$0.2	$1.1	$2.6	$4.4	$7.0
Feb	$0.8	$0.1	$0.9	$0.1	$0.4	$0.5
Mar	$1.6	$0.2	$1.8	$0.7	$1.5	$2.1
Apr	$1.4	$0.7	$2.2	$1.1	$1.0	$2.1
May	$1.4	$0.5	$2.0	$2.0	$0.13	$2.2
Jun	$3.4	$0.5	$3.9	$5.5	$1.4	$7.0
Jul	$6.4	$0.2	$6.6	$2.4	$0.6	$3.1
Aug	$4.7	$0.8	$5.5	$1.7	$0.4	$2.1
Sep	$1.8	$0.2	$2.0	$2.8	$0.2	$2.9
Oct	$1.9	$0.3	$2.2			
Nov	$0.6	$0.3	$0.9			
Dec	$0.9	$1.5	$2.5			
Total (Jan - Sep)	$22.5	$3.4	$25.9	$18.9	$10.1	$29.0
Share (Jan - Sep)	86.9%	13.1%	100.0%	65.2%	34.8%	100.0%
Total	$26.0	$5.5	$31.5	$18.9	$10.1	$29.0
Share	82.4%	17.6%	100.0%	65.2%	34.8%	100.0%

17 Table 4-6 does not include pumped hydro lost opportunity cost credits in Real-Time Lost Opportunity Cost Credits.
18 Table 4-6 includes CT lost opportunity cost forfeiture in the Day-Ahead Lost Opportunity Cost. See "MSRS Report Format Documentation: CT Lost Opportunity Cost Forfeiture, version 5" for more details. <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation.aspx>

Energy Uplift Charges

Energy Uplift Charges

Table 4-7 shows that energy uplift charges for the first nine months of 2025 were $660.6 million, or 1.8 percent of total PJM billing.

Table 4-7 Total energy uplift charges: 2001 through September 2025

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%
2021	$178.4	$87.5	96.3%	0.3%
2022	$284.5	$106.1	59.5%	0.3%
2023	$158.7	($125.8)	(44.2%)	0.3%
2024	$270.0	$111.3	70.1%	0.5%
2025 (Jan - Sep)	$660.6	$390.6	144.7%	1.8%

Table 4-8 shows total energy uplift charges by category for the first nine months of 2024 and 2025. The increase of $440.9 million is comprised of an $87.6 million increase in day-ahead uplift (operating reserve) charges, a $355.8 million increase in balancing generator charges, a $0.4 million decrease in reactive service charges, a $1.0 million decrease in synchronous condensing charges, and a $1.2 million decrease in local congestion charges. Starting with the *2024 Annual State of the Market Report for PJM*, cancellation charges, lost opportunity charges, and dispatch differential lost opportunity cost charges are not broken out individually and are included in the category of balancing generator charges, matching PJM's Market Settlements Reporting System.

Table 4-8 Total energy uplift charges by category: January through September, 2024 and 2025[19]

Category	(Jan - Sep) 2024 Charges (Millions)	(Jan - Sep) 2025 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$93.8	$181.4	$87.6	93.5%
Balancing Operating Reserves	$122.3	$478.1	$355.8	291.0%
Reactive Services	$1.0	$0.6	($0.4)	(41.4%)
Synchronous Condensing	$1.0	$0.0	($1.0)	(100.0%)
Black Start Services	$0.3	$0.4	$0.1	30.4%
Local Congestion Charges	$1.3	$0.1	($1.2)	(90.0%)
Total	$219.7	$660.6	$440.9	200.7%
Energy Uplift as a Percent of Total PJM Billing	0.6%	1.1%	0.8%	147.0%

19 The total PJM billing used in Table 4-8 is different from the total cost shown in Table 1-9. The total PJM billing in Table 4-8 represents the total dollars that pass through the PJM settlement process, while the total cost shown in Table 1-9 is the total cost to load and includes additional costs to load accounted for outside the PJM settlement process.

Table 4-9 compares monthly energy uplift charges by category for January 2024 through September 2025.

Table 4-9 Monthly energy uplift charges: January 2024 through September 2025

	2024 Charges (Millions)						2025 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total
Jan	$32.7	$23.9	$0.9	$0.2	$0.0	$57.7	$153.9	$245.8	$0.0	$0.1	$0.0	$399.8
Feb	$1.2	$5.4	$0.0	$0.0	$0.1	$6.8	$2.5	$32.50	$0.0	$0.0	$0.1	$35.2
Mar	$1.1	$10.8	$0.0	$0.0	$0.0	$12.0	$6.1	$28.58	$0.5	$0.0	$0.1	$35.3
Apr	$12.1	$19.3	$0.0	$0.1	$0.0	$31.5	$3.9	$36.62	$0.0	$0.0	$0.1	$40.6
May	$12.5	$21.0	$0.0	$0.0	$0.0	$33.6	$2.9	$16.64	$0.0	$0.0	$0.0	$19.6
Jun	$14.4	$12.6	$0.0	$1.0	$0.0	$28.1	$5.8	$31.76	$0.0	$0.0	$0.0	$37.6
Jul	$8.4	$11.5	$0.0	$0.0	$0.0	$19.9	$2.3	$46.08	$0.0	$0.0	$0.0	$48.4
Aug	$6.9	$10.9	$0.1	$0.0	$0.0	$17.9	$3.1	$24.06	$0.0	$0.0	$0.0	$27.1
Sep	$4.4	$6.9	$0.0	$0.0	$0.0	$11.3	$0.9	$16.07	$0.0	$0.0	$0.0	$17.1
Oct	$6.4	$9.0	$0.0	$0.0	$0.0	$15.4						
Nov	$3.2	$8.8	$0.0	$0.0	$0.1	$12.1						
Dec	$11.3	$12.1	$0.5	$0.0	$0.0	$23.9						
Total (Jan - Sep)	$93.8	$122.3	$1.0	$1.3	$0.3	$218.7	$181.4	$478.1	$0.6	$0.1	$0.4	$660.6
Share (Jan - Sep)	42.9%	55.9%	0.5%	0.6%	0.1%	100.0%	27.5%	72.4%	0.1%	0.0%	0.1%	100.0%
Total	$114.7	$152.0	$1.5	$1.3	$0.4	$270.0	$181.4	$478.1	$0.6	$0.1	$0.4	$660.6
Share	42.5%	56.3%	0.6%	0.5%	0.2%	100.0%	27.5%	72.4%	0.1%	0.0%	0.1%	100.0%

Table 4-10 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $355.9 million or 291.3 percent in the first nine months of 2025 compared to the first nine months of 2024.

Table 4-10 Balancing operating reserve charges: January through September, 2024 and 2025[20]

Category	(Jan - Sep) 2024 Charges (Millions)	(Jan - Sep) 2025 Charges (Millions)	Change	Percent Change	2024 Share	2025 Share
Balancing Operating Reserve Reliability Charges	$49.4	$327.3	$277.9	563.1%	40.4%	68.5%
Balancing Operating Reserve Deviation Charges	$72.9	$150.8	$77.9	106.8%	59.6%	31.5%
Balancing Operating Reserve Charges for Load Response			$0.0	NA	0.0%	0.0%
Balancing Local constraint Charges	$1.3	$0.1	($1.2)	(90.0%)	1.1%	0.0%
Total	$122.3	$478.1	$355.8	291.0%	100.0%	100.0%

20 Table 4-9 balancing operating reserve total does not match Table 4-10 because Table 4-10 does not include DDLOC charges of $1.6 million.

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-11 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[21] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[22]

Energy Uplift Issues

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases.[24] Since 2018, the cumulative resettlement requests total $17.9 million, of which PJM has agreed and resettled only $3.9 million over the last two years, 22.0 percent, and 1.3 percent are waiting for a PJM response. The remaining 75.8 percent occurred prior to October 2023 and is subject to the OATT's limitation on claims. That limit does not apply and would not have applied if PJM informed the market participant within two years of the occurrence of the issue.[25] PJM should inform market participants of a potential issue when the MMU raises the issue with PJM and the market participant in order to ensure that the issues can be addressed. PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

Table 4-11 Dispatch status, commitment status and uplift eligibility[23]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

21 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
22 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
23 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.
24 To date, the MMU has only requested resettlement of the most egregious cases.
25 OATT § 10.4.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Uplift Forfeiture Rule

The uplift forfeiture rule was introduced in 2000 after PJM observed that in the summer of 1999 units could circumvent the $1,000/MWh offer cap by submitting high offers associated with a long minimum run time (e.g. 24 hours). The rule states that units will not be paid operating reserve credits (uplift) when they are scheduled on their price-based offers during maximum generation conditions and their effective energy offer price exceeds $1,000 per MWh.[26] Maximum generation conditions include maximum generation emergencies, maximum generation emergency alerts, and when PJM schedules units based on the anticipation of a maximum generation emergency or maximum generation emergency alert.

In 2022 and 2023, PJM declared maximum generation conditions on five separate days. During these days, some units received uplift payments in violation of the uplift forfeiture rule. The five days in question are December 23 through 25 of 2022 (Winter Storm Elliott) and July 27 and 28 of 2023. The MMU has determined that, based on the uplift forfeiture rule, balancing operating reserves paid on December 23 and 24 of 2022 should be forfeited. PJM resettled the operating reserve credits paid to units that exceeded an effective offer price of $1,000 per MWh on December 23 and 24, 2022. The total balancing operating reserve credits returned totaled $1.7 million. In the first nine months of 2025, PJM declared maximum generation conditions for January 22, June 22-24, July 14-15, 23-24, and 27-29. The uplift forfeiture rule was triggered on June 23 and 24 because units received uplift with an effective energy price-based offer that exceeded $1,000 per MWh. The uplift payments under the uplift forfeiture rule on June 23 and 24 are under review.

26 See OA Schedule 1 Section 3.2.3 (m) Operating Reserves

The uplift forfeiture rule was also triggered on all of the maximum generation dates in July and analysis and results are pending.

Regulation Market Offsets

PJM does not include regulation market payments as an offset like other market revenues in the operating reserve calculations. Including regulation market revenues would result in lower uplift calculations. Table 4-12 shows that the regulation market revenues in the first nine months of 2025 were $111.5 million and that the balancing generator credits for those units receiving regulation revenues were $39.4 million. The table shows that if the regulation market revenues had been incorporated in the operating reserve calculation as an offset, the balancing generator payment for those units would have been $37.0 million instead of $39.4 million, 6.1 percent lower.

Table 4-12 Adjusted operating reserve credits: January through September, 2025

Month	Regulation Market Revenues (Millions)	Balancing Generator Credits (Millions)	Adjusted Balancing Generator Credits (Millions)	Difference
Jan	$19.8	$25.8	$25.1	($0.7)
Feb	$11.1	$3.4	$3.1	($0.3)
Mar	$11.0	$2.1	$1.8	($0.2)
Apr	$8.5	$2.8	$2.6	($0.2)
May	$8.7	$1.7	$1.5	($0.2)
Jun	$16.5	$1.3	$1.1	($0.2)
Jul	$14.4	$1.3	$0.9	($0.3)
Aug	$9.8	$0.4	$0.3	($0.1)
Sep	$11.8	$0.6	$0.5	($0.1)
Total	$111.5	$39.4	$37.0	($2.4)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[27] Table 4-13 shows the concentration of energy uplift credits. The top 10 units received 37.5

27 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits paid on and after July 1, 2019, on September 10, 2019.

percent of total energy uplift credits in the first nine months of 2025. The top 10 companies received 70.3 percent of total energy uplift credits in the first nine months of 2024.

Table 4-13 Top 10 units and organizations energy uplift credits: January through September, 2025

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$175.6	96.8%	$10.1	5.6%
Balancing	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$88.0	19.7%	$284.5	63.5%
	Lost Opportunity Cost	$6.4	22.2%	$19.7	68.3%
	Dispatch Differential Lost Opportunity Cost	$1.0	50.3%	$1.6	79.9%
	Total Balancing	$95.4	19.9%	$305.8	63.9%
Reactive Services		$0.5	95.3%	$0.5	100.0%
Total		$247.5	37.5%	$464.7	70.3%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-14 through Table 4-18 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Chalk Point 3 and 4 are non-coal steam units in the PEPCO Zone with an ICAP of 582 MW each. In the first nine months of 2025, the Chalk Point 3 and 4 units received a combined $152.2 million in uplift, 23.0 percent of total uplift payments. In the first nine months of 2024, the Chalk Point 3 and 4 units received a combined $32.4 million in uplift, 14.8 percent of total uplift payments.

Brandon Shores 1 and Brandon Shores 2 and Wagner 3 and Wagner 4 submitted retirement notifications to PJM and the MMU in April and October of 2023. Brandon Shores 1 and 2 are coal units in BGE with an ICAP of 635 MW and 638 MW. Wagner 3 and 4 are oil units in BGE with an ICAP of 305 MW and 397 MW. PJM determined that these resources were needed for reliability until transmission upgrades can be completed. In the first nine months of 2025, the Brandon Shores 1 and 2 units received a combined $37.4 million in uplift, 5.7 percent of total uplift payments.

Table 4-14 Top 10 recipients of total uplift: January through September, 2025

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	PEP CHALKPOINT 4 F	PEPCO	$110,814,172	16.8%
2	PEP CHALKPOINT 3 F	PEPCO	$41,386,017	6.3%
3	BC BRANDON SHORES 2 F	BGE	$18,847,115	2.9%
4	BC BRANDON SHORES 1 F	BGE	$18,525,145	2.8%
5	JC REDOAK 1 CC	JCPL	$13,769,290	2.1%
6	PS NEWARK ENERGY CENTER 10 CC	PSEG	$12,363,576	1.9%
7	BC WAGNER 3 F	BGE	$10,210,854	1.5%
8	ME IRONWOOD 1 CC	METED	$8,396,334	1.3%
9	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$6,800,396	1.0%
10	DPL WILDCAT POINT 1 CC	DPL	$6,413,402	1.0%
Total of Top 10			$247,526,300	37.5%
Total Uplift Credits			$660,596,000	100.0%

Table 4-15 Top 10 recipients of day-ahead generation credits: January through September, 2025

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	PEP CHALKPOINT 4 F	PEPCO	$107,440,083	59.2%
2	PEP CHALKPOINT 3 F	PEPCO	$40,904,824	22.5%
3	BC BRANDON SHORES 2 F	BGE	$8,600,781	4.7%
4	BC BRANDON SHORES 1 F	BGE	$6,488,927	3.6%
5	AEP CLINCH RIVER 2 F	AEP	$3,326,932	1.8%
6	BC WAGNER 3 F	BGE	$3,325,484	1.8%
7	AEP CLINCH RIVER 1 F	AEP	$3,168,887	1.7%
8	BC WAGNER 4 F	BGE	$1,462,385	0.8%
9	PEP PANDA 1 F	PEPCO	$434,906	0.2%
10	PEP PANDA 2 F	PEPCO	$433,590	0.2%
Total of Top 10			$175,586,799	96.8%
Total day-ahead operating reserve credits			$181,461,608	100.0%

Table 4-16 Top 10 recipients of balancing generator credits: January through September, 2025

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	JC REDOAK 1 CC	JCPL	$13,763,614	7.6%
2	PS NEWARK ENERGY CENTER 10 CC	PSEG	$12,321,746	6.8%
3	BC BRANDON SHORES 1 F	BGE	$12,035,587	6.6%
4	BC BRANDON SHORES 2 F	BGE	$10,245,746	5.6%
5	ME IRONWOOD 1 CC	METED	$8,395,410	4.6%
6	BC WAGNER 3 F	BGE	$6,866,864	3.8%
7	ACE WEST DEPTFORD CROWN POINT 1 CC	AECO	$6,796,114	3.7%
8	PE PHILLIPS ISL LINWOOD 1 CC	PECO	$6,271,104	3.5%
9	DPL WILDCAT POINT 1 CC	DPL	$6,134,832	3.4%
10	COM 929 JACKSON 2 CC	COMED	$5,182,140	2.9%
Total of Top 10			$88,013,156	48.5%
Total balancing operating reserve credits			$447,746,059	100.0%

Table 4-17 Top 10 recipients of lost opportunity cost credits: January through September, 2025

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	PEP DICKERSON H 1 CT	PEPCO	$1,266,130	4.4%
2	PEP DICKERSON H 2 CT	PEPCO	$888,861	3.1%
3	AEP FOX SQUIRREL 1 SP	AEP	$592,061	2.1%
4	COM BRIGHT STALK 1 WF	COMED	$581,734	2.0%
5	COM BLOOMING GROVE 1 WF1	COMED	$550,908	1.9%
6	VP REMINGTON 4 CT	DOM	$532,706	1.8%
7	COM HIGH TRAIL 1 WIND	COMED	$532,461	1.8%
8	COM LEE DEKALB 1 WF	COMED	$500,000	1.7%
9	DPL ROCK SPRINGS 2 CT	DPL	$497,518	1.7%
10	COM CAYUGA RIDGE 1 WF	COMED	$478,783	1.7%
Total of Top 10			$6,421,161	22.2%
Total lost opportunity cost credits			$28,874,394	100.0%

Table 4-18 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2025

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP SMITH MOUNT 1-5 H	AEP	$245,264	12.5%
2	VP GASTON 1-4 H	DOM	$204,682	10.5%
3	VP KERR DAM 1-7 H	DOM	$158,548	8.1%
4	AP BATH COUNTY 1-6 H	DOM	$119,378	6.1%
5	VP BATH COUNTY 1-6 H	DOM	$92,080	4.7%
6	JC YARDS CREEK 1-3 H	JCPL	$73,521	3.8%
7	VP MARSHRUN 1 CT	DOM	$25,320	1.3%
8	VP MARSHRUN 3 CT	DOM	$22,398	1.1%
9	PEP ST CHARLES-KELSON RIDGE 2 CC	PEPCO	$21,543	1.1%
10	AEP MOUNTAINEER 1 F	AEP	$21,372	1.1%
Total of Top 10			$984,106	50.3%
Total dispatch differential lost opportunity cost credits			$1,956,323	6.8%

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[28] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power to their cost-based offer. Offer capping is designed to set offers at competitive levels.

Table 4-19 shows day-ahead operating reserve credits paid to committed and dispatched units called on during the first nine months of 2025, classified by commitment schedule type. Units using parameter limited schedules received $113.1 million or 62.3 percent of day-ahead operating reserve credits in the first nine months of 2025, units using price-based offers received $30.3 million or 16.7 percent, and units using cost-based offers received $38.1 or 21.0 percent.

Table 4-19 Day-ahead operating reserve credits by Offer Type: January through September, 2025

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Share of DAOR
Cost	$38.1	21.0%
Price	$30.3	16.7%
PLS	$113.1	62.3%
Total	$181.5	100.0%

Table 4-20 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. On weather alert days, PJM can require the use of parameter limited schedules (PLS) to prevent the exercise of market power through the use of inflexible parameters. Of all the day-ahead credits received during days with weather alerts, 1.1 percent went to units that were committed on cost schedules, which are parameter limited, 97.3 percent went to units that were committed on price PLS schedules and 1.5 percent went to units committed on price schedules less flexible than PLS. These results indicate a significant change in PJM's commitment approach during weather alerts. PJM committed only 1.5 percent of units on schedules less flexible than PLS during weather

28 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

alert days in 2025 compared to 17.2 percent during weather alert days in 2024.

Table 4-20 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2025

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$1,267,761	1.1%
Committed on price schedule as flexible as PLS	$59,921	0.1%
Committed on price schedule less flexible than PLS	$1,775,677	1.5%
Committed on price PLS	$113,117,800	97.3%
Total	$116,221,159	100.0%

Gas fired generators may request temporary exceptions to parameter limits such as minimum run time based on restrictions imposed by natural gas pipelines, including ratable takes.[29] Table 4-21 shows the day-ahead operating reserve uplift credits received from 2018 through the first nine months of 2025 by units that submitted parameter exception requests for a 24 hour minimum run time based on gas pipeline restrictions. In the first nine months of 2025, 93 units requested an exception for a 24 hour minimum run time and 60 units received uplift payments amounting to $147.7 million of day-ahead operating reserves and $30.9 million in balancing operating reserves, or 81.4 percent of total day-ahead operating reserves and 6.9 percent of total balancing operating reserves, corresponding to 22.4 percent and 4.7 percent of total uplift.

Table 4-21 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through September 2025

Year	Day-Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Number of Units with 24 Hour Min Run Time Exceptions	Number of Units with 24 Hour Min Run Time Exceptions that Received Uplift
2018	$4.9	$0.7	25	2
2019	$0.2	$0.6	37	12
2020	$0.2	$0.2	13	2
2021	$0.7	$0.6	61	42
2022	$14.4	$9.8	81	38
2023	$10.7	$1.5	75	23
2024	$30.2	$2.4	79	41
2025 (Jan - Sep)	$147.7	$30.9	93	60

Polar Vortex 2025 (January 19 – 23, 2025)

The commitment and dispatch of units by PJM during Polar Vortex 2025 (January 19 through 23, 2025), resulted in significant uplift payments Table 4-22 summarizes the uplift payments by category during Polar Vortex 2025. During Polar Vortex 2025, generating units received $125.8 million in day-ahead operating reserve credits, 69.3 percent of total day-ahead operating reserves during the first nine months of 2025, and 37.1 percent of total uplift during Polar Vortex 2025. During Polar Vortex 2025, generating units received $207.6 million in balancing generator credits, 46.4 percent of total balancing generator credits during the first nine months of 2025 and 61.2 percent of total uplift during Polar Vortex 2025. Total uplift payments during Polar Vortex 2025 were $339.1 million, 51.3 percent of total uplift during the first nine months of 2025.

29 See OA Schedule 1 Section 6.6 (C) Minimum Generator Operating Parameters – Parameter Limited Schedules.

Table 4-22 Energy uplift credits by category during Polar Vortex 2025

Category	Type	2025 Polar Vortex Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Polar Vortex Share of uplift (Jan - Sep) 2025	Share of Polar Vortex Uplift
Day-Ahead	Generators	$125.8	$181.5	69.3%	37.1%
Balancing	Generators	$207.6	$447.7	46.4%	61.2%
	Canceled Resources	$0.0	$0.0	0.0%	0.0%
	Lost Opportunity Cost	$5.7	$28.9	19.6%	1.7%
	Dispatch Differential Lost Opportunity Cost	$0.1	$2.0	3.0%	0.0%
Synchronous Condensing	Synchronous Condensing	$0.0	$0.0	NA	0.0%
	Synchronous Condensing Lost Opportunity Cost	$0.0	$0.0	NA	0.0%
Reactive Services	Generators	$0.0	$0.0	NA	0.0%
	Lost Opportunity Cost	$0.0	$0.5	0.0%	0.0%
	Condensing	$0.0	$0.0	0.0%	0.0%
	Condensing Lost Opportunity Cost	$0.0	$0.0	NA	0.0%
Total		$339.1	$660.6	51.3%	100.0%

Uplift during Polar Vortex 2025 was a result of out of market commitments made by PJM in anticipation of the cold weather. PJM committed units on Friday, January 17 for the January 19, 20 and 21 operating days. These commitments were made in advance of the Day-Ahead Energy Market, before offers were due. Some of the units cleared the Day-Ahead Energy Market economically and did not require uplift payments because their offers were covered by the day-ahead LMP. The rest of the units committed in advance that did not clear the Day-Ahead Market received balancing operating reserves credits because their offers were not covered by the real-time LMP. PJM made these commitments to mitigate generator performance risks based on available information about startup and operating uncertainty due to expected cold temperatures and gas supply illiquidity, including the need for 24 hour minimum run times to meet pipeline requirements for ratable takes.[30] PJM also committed specific units in advance to ensure transmission system reliability. That information was available because in 2024, in order to improve preparations for cold weather, PJM requested that all generators provide their cold weather operating limits, including the operating temperature limit (i.e. lowest ambient temperature at which the plant was designed to operate reliably) and starting temperature limit (i.e. lowest ambient temperature at which the plant could reliably start).

As a result of the low temperatures expected on Monday, January 20 and subsequent days, PJM committed units before temperatures reached the expected low levels. On Friday, January 17 natural gas traded for multiple days, referred to as the weekend package. The weekend package included gas days January 18, 19, 20 and 21, covering the period from Saturday, January 18, 10:00 to Wednesday, January 21, 10:00. PJM committed units on Friday to ensure that they could procure gas over the period of weekend package, reducing the risks of not being able to procure gas during individual days. The same actions were taken on Tuesday, January 21 for gas day January 22 (which covered the period from Wednesday, January 22, 10:00 to Thursday, January 23, 10:00).

The out of market commitments resulted primarily from conservative operations, which PJM declared from January 20 through January 23, but also included unit commitments for transmission constraints.[31] These commitments were made to ensure that supply that in previous events had performed poorly due to cold temperatures and gas supply issues, did not face the same risks. These commitments were not made to meet reserve requirements.

The day-ahead operating reserve credits were the result of units committed for transmission reliability in the day-ahead market (rather than conservative operations), these payments were made to a very small number of units.

Balancing operating reserve credits were the result of multiday commitments to minimize generation performance risk under conservative operations. Those units, mostly gas-fired combined cycle units, were committed ahead of time but did not clear the day-ahead market.

30 *See* "Winter Storm Gerri Review January 13–22, 2024," PJM presentation to the Operating Committee. (February 8, 2024) <https://www.pjm.com/-/media/committees-groups/committees/oc/2024/20240208/20240208-item-11---cold-weather-update.ashx>.

31 See PJM "Manual 13: Emergency Operations," Section 3.2 Conservative Operations Rev. 95 (Feb. 20, 2025).

Table 4-23 summarizes the total energy uplift credits by unit type during Polar Vortex 2025. Combined cycles received $140.1 million in uplift payments, non-coal steam units received $132.4 million and combustion turbines received $63.0 million.

Table 4-23 Total energy uplift credits by unit type during the 2025 Polar Vortex

Unit Type	2025 Polar Vortex Credits (Millions)	(Jan - Sep) 2025 Credits (Millions)	Polar Vortex Share of Uplift (Jan - Sep)	Share of Polar Vortex Uplift
Combined Cycle	$140.1	$156.9	89.3%	41.3%
Combustion Turbine	$63.0	$261.1	24.1%	18.6%
Diesel	$0.4	$2.7	13.4%	0.1%
Hydro	$0.0	$0.9	0.3%	0.0%
Nuclear	$0.0	$0.0	0.0%	0.0%
Solar	$0.0	$0.8	0.0%	0.0%
Steam - Coal	$0.2	$47.6	0.3%	0.0%
Steam - Other	$132.4	$184.6	71.8%	39.0%
Wind	$3.1	$6.0	51.0%	0.9%
Total	$339.1	$660.6	51.3%	100.0%

PJM chose to prepare for the weather related risks of Polar Vortex 2025 in very different ways than for Winter Storm Elliott. Rather than rely on PAI incentives to provide assurance that generators would be ready for cold weather, PJM took direct steps to ensure a reliable outcome. The results of Polar Vortex 2025 vindicated PJM's strategy. PJM took conservative measures to ensure reliability by scheduling resources well in advance of the day-ahead energy market. PJM took additional advance actions to ensure transmission reliability. As there is no multiday market, out of market actions taken before the market starts generally result in uplift. Based on this experience, the rules governing PJM's actions should be more transparent and clearly documented, including defined criteria for taking such actions. In addition, there should be rules about energy offers used for these commitments, and uplift rules should be revised to account for the multiday nature of these commitments. The lessons learned include that conservative operations are preferred to the Winter Storm Elliott approach of assuming that generators would respond, that increased uplift is the expected result and that the process of conservative operations and advance commitments needs to be improved, formalized and made as market oriented as possible in order to minimize uplift and make it as predictable as possible.

Summer Heat Waves in 2025

During the June Heat Wave, lasting June 22 - 26, generating units received $5.8 million in balancing generator credits, 1.3 percent of total balancing generator credits during the first nine months of 2025, and 54.8 percent of total uplift during the June Heat Wave. During the June Heat Wave, generating units received $4.0 million in lost opportunity cost credits, 13.7 percent of total lost opportunity cost credits during the first nine months of 2025 and 37.2 percent of total uplift during the June Heat Wave. Total uplift payments during the June Heat Wave were $10.6 million, 1.6 percent of total uplift during the first nine months of 2025. Of the balancing operating reserve credits during the June Heat Wave, which totaled $5.8 million, $3.1 million was paid to combustion turbines and diesels, $2.6 million was paid to steam units, and $0.9 million was paid to combined cycle units. Of the lost opportunity costs credits paid during the June Heat Wave, which totaled $4.0 million, $3.0 million was paid to flexible resources scheduled day ahead and not committed in real time for the full day-ahead schedule and $1.0 million was paid to units manually dispatched down.

PJM experienced multiple heat waves in July, resulting in periods of high demand, specifically July 14-17 and 23-30. Uplift credits during those days accounted for 6.0 percent of the increase in uplift credits during the first nine months of 2025 compared to the first nine months of 2024.